MONTEREY BAY AIR RESOURCES DISTRICT

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Monterey, CA 93940
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EVALUATION REPORT AND STATEMENT OF BASIS FOR RENEWAL AND SIGNIFICANT MODIFICATION OF THE MAJOR FACILITY REVIEW PERMIT

December 2017
Application TV-0000007

APPLICATION RECEIVED FROM:

Aera Energy LLC
P.O. Box 11164
Bakersfield, CA 93389-1164

PLANT SITE LOCATION:

66893 Sargent Canyon Road
San Ardo, CA 93450

APPLICATION PROCESSED BY:

Armando Jimenez, Air Quality Engineer

Nature of Business: Crude Oil Production

SIC Codes: 1311 - Crude Petroleum and Natural Gas

RESPONSIBLE OFFICIAL:

Name: Mr. W. J. Dittman
Title: Vice President Operations
Phone: (661) 665-3141

ALTERNATIVE RESPONSIBLE OFFICIALS:

Name: Mr. J. M. Ohman
Title: Operations Manager

Name: Mr. M. L. Du Frene
Title: Process Supervisor

FACILITY CONTACT PERSON:

Name: Mr. Tim Parcel
Title: Environmental Advisor
Phone: (831) 385-7704 or (559) 935-7418

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FACILITY DESCRIPTION [TC \l1 "FACILITY DESCRIPTION]

Aera Energy LLC (Aera) operates a crude oil production facility in the San Ardo Field in Southern Monterey County. Aera's operation includes both primary and tertiary crude oil production wells.

These production wells are supported by several categories of equipment necessary to recover heavy crude oil from the production zones. These categories include: 1) steam generators; 2) a cogeneration plant; 3) produced crude oil storage tanks; 4) oil and water separation equipment including heater treaters, free water knockout vessels, induced gas flotation units, skim tanks, produced water tanks, and sand basins; 5) well head casing vent vapor collection system; 6) emergency flare; 7) gasoline dispensing; and 8) crude oil drilling/workover rigs.

Aera's facility is considered a federal Major Source and subject to the Title V permitting program due to the potential to emit oxides of nitrogen (NO_x) and sulfur dioxide (SO_2).

PROJECT DESCRIPTION [TC \l1 "PROJECT DESCRIPTION]

Pursuant to Rule 218 of the Monterey Bay Unified Air Pollution Control District (Air District) Rules and Regulations, the Air District intends to issue a Title V Operating Permit Renewal to Aera.

In addition to the renewal process, the facility is proposing to modify their existing two gas turbines (cogeneration facilities) by removing the continuous emissions monitoring system (CEMS) from the two units and to update the permit to include several equipment modifications that have occurred.

EQUIPMENT DESCRIPTION[tc \l1 "EQUIPMENT DESCRIPTION]

The equipment description will be updated to reflect the equipment modifications that have occurred at the facility. The equipment modifications include the following:

- Remove equipment where the District received both an Authority to Construct (ATC) and Title V Modification applications. Below is the equipment being removed:
    - Remove Cogen C from the list of cogeneration facilities, ATC 12904. Equipment was not installed. Added to Title V Permit under application TV26-04. ATC cancelled in April 2014.
    - Remove SulFerox desulfurization plant, ATC 13721. Remove references to this equipment throughout the permit. Added to Title V Permit under application TV44-02. ATC cancelled in April 2014.
    - Remove equipment for the new water reclamation plant, application 14944 (no ATC was issued). Added to Title V Permit under application TV44-04.
    - Remove equipment upgrades under the Central Treatment Complex project, ATC 14583. Added to Title V Permit under application TV44-05. ATC cancelled in April 2014.
        - Crude Oil Heaters, with identification numbers CTB-1 through CTB-5, CTB-7 and CTB-8, will not be replaced.
        - The Recovery Gas Treatment Plant will not be replaced by a new 12.0 MM

Scf/Day emergency only Utility flare.

- Waste Water Facility Including Water Reclamation Plant will not be replaced.

- Update equipment identification numbers.
- Update the rating of the heat input rating of the oil heater treaters with identification number CTB-1 through CTB-4.

The equipment description will be updated as follows:

1. Oil Recovery And Steam Injection Wells.

2. Drilling Rigs With Diesel Fired Internal Combustion Engines.

3. Cogeneration Facilities, ~~Three~~ Two Units (Cogen A~~,~~ & B ~~& C~~) Each Consisting Of:

   a. Solar Centaur T-4501 Gas Turbine, Fired On Natural Gas ~~And/Or Produced Gas Treated By The Desulfurization Plant~~, Rated At 61.5 MMBtu/Hr Maximum Heat Input And 3.2 MW Electrical Output, Evaporative Cooler On Turbine Inlet, Water Injection For NO_x Control (0.5 Lbm H_2O/Lbm Fuel).

   b. Heat Recovery Steam Generator With Duct Burner Fired On Natural Gas ~~And/Or Produced Gas Treated By The Desulfurization Plant~~, 38.7 MMBtu/Hr Maximum Heat Input, Steam Output Rating: 57,180 Lbs/Hr @ 1054 psia and 551°F.

   c. NO_x Abatement System, Zeolite Catalyst And Ammonia Injection System.

4. One Steam Generator (Identification Number 30-13), Fired On Natural Gas ~~And/Or Produced Gas Treated By The Desulfurization Plant,~~ 62.5 MMBtu/Hr Maximum Heat Input. With Flue Gas Recirculation.

5. Nine Steam Generators ~~(Identification Numbers 22-1 Through 22-4, And 30-1 Through 30-5)~~ (Identification Numbers 12-2 Through 12-5, 12-7 Through 12-10, And 30-1), Fired On Natural Gas ~~And/Or Produced Gas Treated By The Desulfurization Plant~~, 85 MMBtu/Hr Maximum Heat Input. With Flue Gas Recirculation.

6. Two Steam Generators With Packed Tower Scrubber System (Identification Numbers 30-6 And 30-10A), Fired On Natural Gas And/Or Produced Gas ~~Treated By The Desulfurization Plant And/Or Produced Gas Which Bypasses The Desulfurization Plant~~, 62.5 MMBtu/Hr Maximum Heat Input.

7. One Steam Generator With Three Tray Scrubber System (Identification Number 30-9), Fired On Natural Gas And/Or Produced Gas ~~Treated By The Desulfurization Plant And/Or Produced Gas Which Bypasses The Desulfurization Plant~~, 62.5 MMBtu/Hr Maximum Heat Input.

8. Casing Gas Processing Plant ~~Including SulFerox Desulfurization Unit~~ With A Design Capacity Of 10.0 MM Scf/Day.

9. ~~Five~~ Crude Oil Heater Treater~~s~~ (Identification Number~~s~~ CTB-1 ~~Through CTB-5~~), Fired On Natural

Gas~~, And/Or Produced Gas Treated By The Desulfurization Plant With Number 6 Fuel Oil Standby, Each Unit~~ Equipped With Two Burners, Each Burner Has A Maximum Heat Input Rating Of ~~6.3~~ 4.2 MMBtu/Hr. ~~These Five Crude Oil Heater Treaters Will Be Replaced By Seven New Un-Fired Free Water Knockout Vessels.~~

10. Three Crude Oil Heater Treaters (Identification Numbers CTB-2, CTB-3 And CTB-4), Fired On Natural Gas, Each Unit Equipped With Two Burners, Each Burner Has A Maximum Heat Input Rating Of 2.4 MMBtu/Hr.

~~10.~~ 11. ~~Two~~ Three Crude Oil Heater Treaters (Identification Numbers CTB-5, CTB-7 And CTB-8), Fired On Natural Gas ~~And/Or Produced Gas Treated By The Desulfurization Plant~~, Each Unit Equipped With Two Burners, Each Burner Has A Maximum Heat Input Rating Of 6.3 MMBtu/Hr. ~~These Two Crude Oil Heater Treaters Will Be Replaced By Three New Un-Fired Heater Treaters.~~

~~11.~~ 12. Recovery Gas Treatment Plant Including Sulfatreat Vessels And Enclosed Ground Flare. ~~This Equipment Will Be Removed And Replaced By A New 12.0 MM Scf/Day Emergency Use Only Utility Flare.~~

~~12.~~ 13. Oil Treating Facility Including Truck Loadout.

~~13.~~ 14. Waste Water Facility Including Water Reclamation Plant. ~~The Waste Water Facility Will Be Replaced And Incorporated Into The New Central Treatment Complex And The Water Reclamation Plant Will Be Replace With New Equipment.~~

~~14.~~ 15. Ancillary Equipment:

Gasoline Dispensing Facility.

Laboratory Fume Hood.

The equipment description on the Title V permit will be updated to include the District permit to operate (PTO) number for each permitted emission unit.

APPLICABLE FEDERAL REQUIREMENTS [TC \l1 "APPLICABLE FEDERAL REQUIREMENTS]

Applicable Requirement	Equipment Affected
Rule 200, Permits Required	Facility Wide
Rule 207, Review of New or Modified Sources	Facility Wide
Rule 213, Continuous Emissions Monitoring	Gas Turbines
Rule 214, Breakdown Condition	Facility Wide
Rule 218, Title V: Federal Operating Permits	Facility Wide
Rule 300, District Fees	Facility Wide

Applicable Requirement	Equipment Affected
Rule 400, Visible Emissions	Facility Wide
Rule 403, Particulate Matter	Diesel Fired Drilling Rigs, Gas Turbines, Steam Generators & Crude Oil Heaters Treaters
Rule 404, Sulfur Compounds and Nitrogen Oxides	Diesel Fired Drilling Rigs, Gas Turbines, Steam Generators & Crude Oil Heaters Treaters
Rule 412, Sulfur Content Fuels	Diesel Fired Drilling Rigs, Gas Turbines, Steam Generators & Crude Oil Heaters Treaters
Rule 413, Removal of Sulfur Compounds	Diesel Fired Drilling Rigs, Gas Turbines, Steam Generators & Crude Oil Heaters Treaters
Rule 416, Solvents	Facility Wide
Rule 417, Storage of Organic Liquids	Oil Treating Facility, Waste Water Facility & Gasoline Dispensing Facility
Rule 418, Transfer of Gasoline into Stationary Storage Containers	Gasoline Dispensing Facility
Rule 420, Effluent Oil Water Separators	Waste Water Facility
Rule 426, Architectural Coatings	Facility Wide
Rule 427, Steam Drive Crude Oil Production Wells	Facility Wide
Rule 1002, Transfer of Gasoline into Vehicle Fuel Tanks	Gasoline Dispensing Facility
40 CFR Part 60, Subpart A, New Source Performance Standards (NSPS), General Provisions	Facility Wide
40 CFR Part 60, Subpart Dc, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	Steam Generators
40 CFR Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	Gas Turbines
40 CFR Part 60, Subpart KKKK, Standard of Performance for Stationary Combustion Turbines	Gas Turbines
40 CFR Part 60, Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015	Facility Wide
40 CFR Part 60, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015	Facility Wide
40 CFR Part 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines	Gas Turbines
40 CFR Part 63, Subpart DDDDD, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	Steam Generators
40 CFR Part 63, Subpart JJJJJJ, NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources	Steam Generators
40 CFR Part 64, Compliance Assurance Monitoring	Gas Turbines & Steam Generators

COMPLIANCE DETERMINATION FOR APPLICABLE FEDERAL REQUIREMENTS [TC \l1 "COMPLIANCE DETERMINATION FOR APPLICABLE FEDERAL REQUIREMENTS]

Rule 200 – Permits Required
This is the regulation which establishes the requirement for District permits. The facility has been in compliance with the requirements of this rule, and continued compliance is expected.

Rule 201 – Sources Not Requiring Permits
This is the regulation which identifies the types of processes and equipment not subject to permit.

Rule 207 – Review of New or Modified Sources
Rule 207 applies to all new stationary sources and all modifications to existing stationary sources which, after construction or modification, emit or have the potential to emit any affected pollutants. The requested modifications do not result in an emissions increase. Thus, the project is not subject to the requirements of this rule.

This facility and some of the equipment predate the NSR requirements. Newer equipment has undergone New Source Review (NSR); therefore, conditions on these NSR permits are federally enforceable and will be included on this permit.

Rule 213 – Continuous Emissions Monitoring
The requirements of Rule 213 apply to electric power generation equipment subject to Title IV (Acid Deposition Control) of the federal Clean Air Act with nameplate generation capacities of at least 25 megawatts (MW); to fossil fuel-fired steam generators with a rated heat input of 250 million British thermal units (MMBtu) or greater per hour; and to any source required to install CEMS as required to prove compliance with air pollution requirements pursuant to an authority to construct or permit to operate.

The Cogen facilities have a rated heat input of have a nameplate capacity of 3.2 MW and the heat recovery steam generators have a rated heat input of less than 250 MMBtu per hour. Thus, Aera's proposal to remove the CEMS will be consistent with the requirements of Rule 213.

Rule 214 – Breakdown Condition
The requirements of Rule 214 apply to any breakdown which results in a violation of any State law, District Regulation, permit, or Hearing Board order.

Permit conditions are included on the permit to comply with the requirements of Rule 214.

Rule 218 – Title V: Federal Operating Permits
Aera is subject to the requirements of Rule 218 and operates under a Title V permit. The proposed removal of the CEMS is a relaxation in monitoring. According to Rule 218 Section 2.27.3, a modification to a federally enforceable condition on a permit to operate which significantly changes monitoring conditions is a significant permit modification to the Title V permit. Aera has applied to modify their Title V permit.

In their original application, the facility requested a permit shield from certain applicable requirements which are addressed in this evaluation. As required by this rule, a provision will be included on the permit which specifies which applicable requirements the facility is shielded from and basis for the permit shield.

Permit conditions are included on the permit to comply with Rule 218.

Rule 300 – District Fees (Section 4.4 Emission Statement)
The facility is subject to the Emission Statement as required by Section 182(a)(3)(B)(ii) of the Federal Clean Air Act. Historically, the facility has submitted the required Emission Statement.

Permit conditions are included on the permit to comply with the requirements of Rule 300.

Rule 308 – Title V: Federal Operating Permit Fees
This is the District's fee rule for Title V. Appropriate conditions will be included on the Title V permit to ensure compliance with the fee provisions contained in this rule.

Rule 400 – Visible Emissions
The requirements of Rule 400 apply to the emissions from the facility.

Permit conditions are included on the permit to comply with Rule 400.

Rule 403 – Particulate Matter
The requirements of Rule 403 apply to any source discharging particulate matter while operating within the Air District. The Rule contains a limit of 0.15 grains per dry cubic foot emission standard. Section 1.3.1 exempts stationary internal combustion engines from meeting the requirements of this Rule.

Cogeneration Facilities – Based upon the requirements of Rule 403, the volumetric flow rate of 29,700 SDCFM for the gas turbines would establish an emission limit of 38.2 lbs PM/hr [(29,700 SDCFM)*(0.15 grains/SDCF)*(1 lb/7,000 grains)*(60 M/Hr) = 38.2 lbs PM/hr]. From the NSR permits, the PM emission limit for each of the turbines is 0.81 lbs/hr which is well below the Rule 403 standard. Therefore, no monitoring/testing or record keeping will be included on the permit to show compliance with the grain loading requirement for this equipment.

Steam Generators, 62.5 MMBtu/hr, Natural Gas Fired – Based upon the requirements of Rule 403, the volumetric flow rate of 9,000 SDCFM for these steam generators would establish an emission limit of 11.6 lbs PM/hr [(9,000 SDCFM)*(0.15 grains/SDCF)*(1 lb/7,000 grains)*(60 M/Hr) = 11.6 lbs PM/hr]. AP-42 establishes an emission limit of 7.6 lbs PM/MMCF (from Table 1.4-2 dated 7/98) which would equate to an hourly emission of 0.45 lbs PM/hr [(62.5 MMBtu/hr)(1 MMCF/1,050 MMBtu)(7.6 lbs PM/MMCF) = 0.45 lbs PM/hr]. This calculated value is well below the Rule 403 grain loading standard. Therefore, no monitoring/testing or record keeping will be included on the permit to show compliance with the grain loading requirement for this equipment.

Steam Generators, 85 MMBtu/hr, Natural Gas Fired - Based upon the requirements of Rule 403, the volumetric flow rate of 12,340 SDCFM for these steam generators would establish an emission limit of 15.9 lbs PM/hr [(12,340 SDCFM)*(0.15 grains/SDCF)*(1 lb/7,000 grains)*(60 M/Hr) = 15.9 lbs PM/hr]. AP-42 establishes an emission limit of 7.6 lbs PM/MMCF (from Table 1.4-2 dated 7/98) which would equate to an hourly emission of 0.62 lbs PM/hr [(85 MMBtu/hr)(1 MMCF/1,050 MMBtu)(7.6 lbs

PM/MMCF) = 0.62 lbs PM/hr]. This calculated value is well below the Rule 403 grain loading standard. Therefore, no monitoring/testing or record keeping will be included on the permit to show compliance with the grain loading requirement for this equipment.

Steam Generators With Scrubber Systems - Based upon the requirements of Rule 403, the volumetric flow rate of 9,000 SDCFM for these steam generators would establish an emission limit of 11.6 lbs PM/hr [(9,000 SDCFM)*(0.15 grains/SDCF)*(1 lb/7,000 grains)*(60 M/Hr) = 11.6 lbs PM/hr]. From the NSR permits, the PM emission limit for each of the steam generators with scrubbers is 0.50 lbs/hr which is well below the Rule 403 standard. Therefore, no monitoring/testing or record keeping will be included on the permit to show compliance with the grain loading requirement for this equipment.

Crude Oil Heater Treaters - Based upon the requirements of Rule 403, the volumetric flow rate of 1,220 SDCFM firing natural gas would establish an emission limit of 1.6 lbs PM/hr on natural gas [(1,220 SDCFM)*(0.15 grans/SDCF)*(1 lb/7,000 grains)*(60 M/Hr) = 1.6 lbs PM/hr]. AP-42 establishes an emission limit of 7.6 lbs PM/MMCF NG (from Table 1.4-2 dated 7/98) which would equate to an hourly emission of 0.09 lbs PM/hr while firing on natural gas [(12.6 MMBtu/hr)(1 MMCF/1,050 MMBtu)(7.6 lbs PM/MMCF) = 0.09 lbs PM/hr]. The gas emissions calculated based on AP-42 factors well are below the Rule 403 grain loading requirement. Therefore, no monitoring/testing or record keeping will be included on the permit to show compliance with the grain loading requirement for this equipment.

Rule 404 – Sulfur Compounds and Nitrogen Oxides
The requirements of Rule 404 apply to the emissions from the facility. This rule limits sulfur compounds calculated as sulfur dioxide at 0.2 percent by volume (2,000 ppmv) and limits NOx emissions to 140 pounds per hour.

Diesel Fired Drilling Rigs – Compliance with the 0.2% by volume (2,000 ppmv) limit for SO_2 is assumed due to the following calculation based upon the AP-42 emission factor of 0.29 lbs SO_2/MMBtu (from table 3.3-1 dated 10/96) heat input. Utilizing this emission factor and the F factor from EPA method 19, the SO_2 concentration for a diesel engine would equate to 3.1 ppmv [(0.29 lbs SO_2/MMBtu)*((MM lbmoles air)/(64.1 lbmole SO_2))*((379 Ft^3 Air)/(lbmole air))/((9,190 SDCFM)*(60 M/Hr)) = 3.1 ppmv] This value is well below the 2,000 ppmv SO_2 allowed in this rule. Therefore, no monitoring/testing or record keeping will be included on the permit to show compliance with the SO_2 limit for this equipment.

Compliance with the NO_x limit of 140 lb/hr from the diesel drilling rigs is assumed due to the following emission calculation based upon the AP-42, Table 3.3-1 dated 10/98, emission factor of 0.031 Lbs NO_x/Hp-hr. An emission rate of 140 lbs/hr would equate to an engine of 4,516 Hp [(140 lbs/hr)/(0.031 lbs NO_x/Hp-hr) = 4,516 Hp]. The engines on the drill rigs are all below 1,200 hp and are not capable of exceeding the 140 lb hour NO_x limit. Therefore, no monitoring/testing or record keeping requirements will be included on the permit to show compliance with the 140 lb/hr NO_x limit for this equipment.

Cogeneration Facilities – Compliance with the 0.2% by volume (2,000 ppmv) limit for SO_2 is assured due to these units being fired exclusively on natural gas and based upon the SO_2 limit contained in the NSR permit of 0.1 lb/hr. The SO_2 concentration at this permitted emission level would be 0.33 ppmv [(0.1 lbs SO_2/hr)*((MM lbmoles air)/(64.1 lbmole SO_2))*((379 Ft^3 Air)/(lbmole air))/((29,700 SDCFM)*(60 M/Hr)) = 0.33 ppmv]. This value is well below the 2,000 ppmv SO_2 allowed in this rule.

Compliance with the 140 lb/hr NO_x limit is assured due to the emission limit contained in the NSR permits. The NO_x limit contained in the NSR permits is 3.8 lbs/hr.

Therefore, the Rule 404 emission limits will be subsumed under the NSR limits for the cogeneration facilities which will be included on the Title V permit.

Steam Generators, Natural Gas Fired – Compliance with the 0.2% by volume (2,000 ppmv) limit for SO_2 is assured due to these units being fired exclusively on natural gas. Therefore, no monitoring/testing or record keeping requirements will be included on the permit to show compliance with the 0.2% by volume SO_2 limit for this equipment.

62.5 MMBtu/hr Steam Generators – Compliance with the 140 lb/hr limit is assumed due to the following emission calculations based upon the AP-42 emission factors of 140 lbs NO_x/MMCF natural gas burned (from AP-42 Table 1.4-2 dated 1/95). The steam generators are rated at 62.5 MMBtu/Hr which equates to 8.3 lbs/hr [(62.5 MMBtu/Hr)(1 MMCF/1,050 MMBtu)(140 lbs/MMCF) = 8.3 lbs NO_x/Hr]. The steam generators are not capable of exceeding the 140 lb hour NO_x limit.

85 MMBtu/hr Steam Generators – Compliance with the 140 lb/hr limit is assured due to the NSR limits included in the permit. The limit is 0.93 lbs/hr, which is well below the rule limits. Therefore, no monitoring/testing or record keeping requirements will be included on the permit to show compliance with the 140 lb/hr NO_x limit for the natural gas fired steam generators.

Steam Generators With Scrubber Systems – Compliance with the 0.2% by volume (2,000 ppmv) limit for SO_2 is assured due to the SO_2 limit contained on the NSR permits of 6.33 lbs/hr. The SO_2 concentration at this permitted emission level would be 69.3 ppmv [(6.33 lbs SO_2/hr)*((MM lbmoles air)/(64.1 lbmole SO_2))*((379 Ft^3 Air)/(lbmole air))/((9,000 SDCFM)*(60 M/Hr)) = 69.3 ppmv]. This value is well below the 2,000 ppmv SO_2 allowed in this rule.

Compliance with the 140 lb/hr NO_x limit is assured due to the emission limit contained in the NSR permits. The NO_x limit contained on the NSR permits is 6.25 lbs/hr. This value is well below the below the 140 lb/hr NO_x limits allowed in this rule.

Crude Oil Heater Treaters – Compliance with the 0.2% by volume (2,000 ppmv) limit for SO_2 is assumed while firing on natural gas.

Compliance with the 140 lb/hr NO_x limit is assumed due to the following emission calculation. AP-42 establishes emission factor of 100 lbs NO_x/MMCF of natural gas (from AP-42 Tables 1.3-2 dated 1/95) which would equate to an hourly emission of 1.2 lbs NO_x/hr while firing on natural gas [(12.6 MMBtu/hr)(1 MMCF/1050 MMBtu)(100 lbs NO_x/MMCF) = 1.2 lbs NO_x/hr]. The heater treaters are not capable of exceeding the 140 lb hour NO_x limit. Therefore, no monitoring/testing or record keeping requirements will be included on the permit to show compliance with the 140 lb/hr NO_x limit for this equipment.

Rule 412 – Sulfur Content of Fuels

This rule which requires that the sulfur content of fuels combusted be less than 50 grains per 100 cubic feet for gaseous fuel and less than 0.5% by weight for liquid or solid fuel is applicable to this facility. Combustion of natural gas assures compliance with the 50 grain limit while the backup fuel is Residual Oil Number 6 with sulfur content below 0.5%. Diesel fuel combusted in the internal combustion engines is in compliance with the less than 0.5% by weight sulfur content.

Note that the combustion of casing gas is not subject to the requirements of this rule, as it is exempted from the requirements of Rule 412 by Rule 413 as discussed below.

Rule 413 – Removal of Sulfur Compounds
This rule provides that Rule 412 shall not apply where sulfur compounds are removed from combustion products, or a mixture of fuels are used such that the emission of sulfur compounds to the atmosphere are no greater than the emission if the source was combusting a liquid or solid fuel with a sulfur content less than 0.5% by weight.

The following calculations verify that the combustion of casing gas is in compliance with Rule 413 requirements, and therefore not subject to the requirements of Rule 412. Sulfur emissions from a liquid fuel (diesel) with 0.5% by weight sulfur equate to 0.526 lbs SO_2/MMBtu [(0.5 lb Sulfur/100 lbs fuel)(1.0 lb fuel/19,000 Btu)(10^6 BTU/MMBtu)(64 lbs SO_2/32 lbs Sulfur) = 0.526 lbs SO_2/MMBtu], whereas the sulfur emissions from the combustion of casing gas are limited by the NSR permits to 152 lbs/MMCF (this is based on a 3% inlet H_2S concentration and a scrubber removal efficiency of 97%) which equates to 0.276 lbs SO_2/MMBtu [(152 lbs/MMCF)(1.0 CF/550 BTU)(10^6 Btu/MMBtu) = 0.276 lbs SO_2/MMBtu]. The emissions of the casing gas from the steam generator with the scrubber are less than the combustion of a liquid fuel with 0.5% sulfur by weight. Therefore, no monitoring/testing or record keeping will be required to ensure compliance with the Rule 413 requirements, but testing will be required to ensure compliance with the NSR established SO_2 emission limit which can be used as a surrogate to show continuing compliance with this rule requirement.

Rule 416 – Organic Solvents
This rule establishes specific limits on solvent usage and record keeping where the material is utilized as a dissolver, viscosity reducer or cleaning agent.

Appropriate conditions will be included on the permit to ensure compliance with this rule.

Rule 417 – Storage of Organic Liquids
This rule requires vapor loss control devices on organic storage tanks if the organic liquid stored has a true vapor pressure of 1.5 psi at actual storage conditions.

The gasoline dispensing facility and the waste water facility are not subject to the requirements of Rule 417 based upon the exemptions contained in section 1.3. The gasoline storage tank has a capacity of 4,000 gallons, while Rule 417 is only applicable to tanks greater than 150,000 liters (39,630 gallons). The actual vapor pressure of the stored liquid in waste water tanks is 0.17 psia, well below the 1.5 psia for triggering Rule 417 requirements.

The oil treating facility is subject to the requirements of this rule. The tanks at the oil treating facility are vented to the vapor recovery system meeting the requirements of section 3.1 of the rule with a minimum destruction efficiency of 95%.

Appropriate conditions will be included on the permit to ensure compliance with the provisions of this rule.

Rule 418 – Transfer of Gasoline into Stationary Storage Containers
This rule requires that the gasoline storage tank have a submerged fill pipe and that Phase I Vapor recovery be utilized when filling the tank. The rule also requires specific record keeping regarding the quantity of fuel delivered to the facility. The facility is in compliance with the requirements of this rule.

Appropriate conditions will be included on the permit to ensure compliance with the requirements of this rule.

Rule 420 – Effluent Oil Water Separators
This rule requires vapor loss control devices on any vessel or device operated to recover oil from effluent water where 200+ gallons a day of petroleum products are recovered if the Reid vapor pressure is 0.5 psi or greater. The Reid vapor pressure of the heavy crude processed in the effluent oil water separators is 0.22 psi. Therefore, the effluent oil water separators at this facility are not subject to the requirements of this rule.

Appropriate conditions will be included on the permit to ensure compliance with the provisions of this rule if organic materials are processed that have a Reid vapor pressure equal or greater than 0.5 psi.

Rule 426 – Architectural Coatings
This rule is applicable to all architectural coatings and limits the VOC content of these coatings. The facility is in compliance with the requirements of this rule.

Appropriate conditions are included on the permit to ensure compliance with the provisions of this rule.

Rule 427 – Steam Drive Crude Oil Production Wells
This rule is applicable to steam enhanced production wells at the facility. The facility is in compliance with the requirements of this rule by collecting the gas from the steam enhanced production wells and routing to the vapor recovery system. The gas is then processed by the vapor recovery system, and finally combusted as fuel in one of the steam generators.

Appropriate conditions are included on the permit to ensure compliance with the provisions of this rule.

Rule 433 – Organic Solvent Cleaning
This rule contains specific operational and record keeping requirements for solvent cleaning and degreasing operations.

Appropriate conditions are included on the permit to ensure compliance with the provisions of this rule.

Rule 1002 – Transfer of Gasoline into Vehicle Fuel Tanks
This rule contains specific requirements for the installation and operation of ARB Certified Vapor Recovery (phase II) systems on gasoline dispensing facilities.

Appropriate conditions are included on the permit to ensure compliance with the provisions of this rule.

40 CFR Part 60, Subpart A – New Source Performance Standards, General Provisions
The facility is subject to the requirements of Section §60.7 (notification and record keeping), Section §60.8 (performance tests), §60.11 (compliance with standards and maintenance requirements), and §60.13 (monitoring requirements) because the facility is subject to the requirements of 40 CFR Part 60, Subparts Dc and GG. The facility has requested that the requirements of Subpart A be subsumed under the NSR permit requirements.

The District agrees, and asserts that compliance with the conditions on the Title V permit shall be considered compliance with the monitoring, record keeping, and reporting requirements contained in 40 CFR Parts 60.7, 60.8, 60.11, and 60.13.

40 CFR Part 60, Subpart Dc, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The requirements of this Subpart apply to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBtu/hr (29 MW) or less, but greater than or equal to 10 MMBtu/hr (2.9 MW). Aera's steam generating equipment are subject to the requirements of this Subpart. However, no SO_x and PM requirements are imposed due to the fact that no heat input is provided by coal, oil, or wood.

No conditions pertaining to this Subpart will be included on the permit.

40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines

The gas turbines both have a maximum heat input of 61.5 MMBtu per hour which exceeds the applicability threshold of 10 MMBtu/hr. The gas turbine uses Selective Catalytic Reduction (SCR) and water injection to control NO_x formation.

The NO_x emission factor from Section §60.332(a)(2) would be 150 ppmvd. This 150 ppmvd limit far exceeds the NSR permit limit of 3.8 lbs NO/hr which equates to 17.6 ppmv [(3.8 lbs NO/Hr) (1E06) (379 ft^3/lbmole) (lbmole/46 lb NO) (hr/60 min) (min/29,700 ft^3) = 17.6 ppmv] established by District Rule 207. Therefore, the NO_x limit from the NSPS is subsumed under the NSR permit requirement that is included on the Title V permit.

The SO_2 limit from Section §60.333 would be 150 ppmv. Compliance with this limit is assumed due to these units being fired exclusively on natural gas and based upon the SO_2 limit contained in the NSR permits of 0.1 lb/hr per unit. The SO_2 concentration at this permitted emission level would be 0.33 ppmv [(0.1 lbs SO_2/Hr) (1E06) (379 ft^3/lbmole) (lbmole/64.1 lb SO_2) (hr/60 min) (min/29,700 ft^3) = 0.33 ppmv]. This value is well below the 150 ppmv SO_2 allowed for in the NSPS. Therefore, the SO_2 emission standard from this NSPS is subsumed under the NSR permit requirement that is included on the Title V permit.

Section §60.334(a) requires turbines using water injection to control NO_x formation to install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. Per Section §60.334(b), gas turbines which use water or steam injection to control NO_x emissions may, as an alternative to operating the continuous monitoring system described by Section 60.334(a), install, certify, maintain, operate, and quality-assure a CEMS consisting of NO_x and O_2 monitors.

Aera currently operates both a CEMS (consisting of NO_x and O_2 monitors) and a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine system. Since Section §60.334 does not require operation of both systems, Aera can retain the water to fuel ratio monitoring and remove the CEMS requirements.

Per Section §60.334(g), Aera is required to develop and keep on-site a parameter monitoring plan for District approval which explains the procedures used to document proper operation of the water injection control systems used for NO_x emission reduction. The plan shall include the parameters monitored and acceptable ranges of the parameters as well as the basis for designating the parameters and acceptable ranges for the water injection control systems. Aera has proposed to monitor the following parameters: water/fuel ratio, ammonia (NH_3) injection rate and catalyst temperature. [REF _Ref485969748 \h * MERGEFORMAT] shows Aera's proposed gas turbine parameter monitoring plan.

Table [SEQ Table * ARABIC]. Gas turbine parameter monitoring plan.

Parameter:	Minimum Limit:	Maximum Limit:	Reporting:
Catalyst temperature	450°F	900°F	Average hourly
Water/Fuel ratio	0.5 lb H_2O/lb fuel	0.9 lb H_2O/lb fuel	Average hourly
NH_3 injection rate	900 liters/hr	1,800 liters/hr	Average hourly

The proposed monitoring plan is based upon historical source test data conducted for the gas turbines. The District agrees that the proposed monitoring plan will ensure compliance with the NO_x emission limits. In addition to the proposed monitoring plan, the facility is required to conduct annual source testing of the cogeneration units, which will ensure continued compliance of the emissions limits.

The permit conditions will be modified to include the new parameter monitoring plan.

<u>40 CFR Part 60, Subpart KKKK - Standard of Performance for Stationary Combustion Turbines</u>

The gas turbine/HRSG sets were constructed before February 18, 2005 and are exempt from the requirements of 40 CFR Part 60 Subpart KKKK.

No conditions pertaining to this Subpart will be included on the permit.

<u>40 CFR Part 63, Subpart YYYY - NESHAP for Stationary Combustion Turbines</u>

The gas turbine/HRSG sets are not subject to this rule because the facility is not a major source of hazardous air pollutants.

No conditions pertaining to this Subpart will be included on the permit.

<u>40 CFR Part 60, Subpart OOOO, NSPS for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015</u>

The requirements of this Subpart apply to the following types of equipment that were constructed, modified, or reconstructed between August 23, 2011 and September 18,2015:

- Gas wells
- Centrifugal compressors
- Reciprocating compressors
- Natural gas-driven pneumatic controllers with continuous bleed rate greater than 6 scfh
- Storage vessels with potential VOC emissions equal to or greater than 6 tpy (tons per year)
- Group of equipment (except compressors) within a process unit
- Sweetening units located at onshore natural gas processing plants.

Aera did not construct, modify, or reconstruct any equipment that would fall into the affected equipment under this Subpart between August 23, 2011 and September 18, 2015.

No conditions pertaining to this Subpart will be included on the permit.

40 CFR Part 60, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

The requirements of this Subpart apply to the following types of equipment that were constructed, modified, or reconstructed after September 18, 2015:

- Hydraulic fractured/refractured wells
- Centrifugal compressors
- Natural gas-driven pneumatic controllers with continuous bleed rate greater than 6 scfh
- Storage vessels with potential VOC emissions equal to or greater than 6 tpy (ton per year)
- Natural gas-driven pneumatic pumps
- Well site
- Compressor station

Aera has provided an applicability analysis for each of the equipment subject to Subpart OOOOa. Aera's analysis is shown below:

> *Hydraulic factured wells*
> Aera has not utilized hydraulic fracturing methods on any existing well and has no future plans to hydraulically fracture a well within the San Ardo Oil Field. Therefore, this section of Subpart OOOOa is not applicable to the facility.
>
> *Centrifugal compressors*
> The facility has no centrifugal compressors.
>
> *Reciprocating compressors*
> Aera has not constructed, modified or reconstructed a reciprocating compressor within the San Ardo Oil Field since September 18, 2015. This section of Subpart OOOOa is not applicable to the facility.
>
> *Natural gas-driven pneumatic controllers*
> Aera has not constructed, modified or reconstructed a natural gas-driven pneumatic controller within the San Ardo Oil Field since September 18, 2015. This section of Subpart OOOOa is not applicable to the facility.
>
> *Storage vessels with potential VOC emissions greater than 6 tpy*
> Aera has not constructed, modified or reconstructed a storage vessel within the San Ardo Oil Field since September 18, 2015. This section of Subpart OOOOa is not applicable to the facility.
>
> *Natural gas-driven pneumatic pumps*
> Aera has not constructed, modified or reconstructed a natural gas-driven pneumatic pump within the San Ardo Oil Field since September 18, 2015. This section of Subpart OOOOa is not applicable to the facility.
>
> *Compressor Stations*
> There are no compressor stations located within Aera's San Ardo operations. This section of Subpart OOOOa is also not applicable.

The District agrees with Aera's applicability analysis for the above equipment.

In addition to the applicability analysis for the above equipment, the facility also provided applicability analysis for a "Well Site". Section §60.5430a defines a well site as one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries). Aera has determined that the facility's Oil Treatment Facility, or OTF, is subject to the requirements for fugitive emissions from well sites. The OTF is receiving fluids from wells drilled after September 18, 2015.

The Small Entity Compliance Guide for Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, the basic requirements of a fugitive emissions monitoring plan for the collection of fugitive emissions components at well sites or compressor stations within each company defined area, conducting initial and periodic monitoring, repair of any components found to be leaking, and verification (survey) that the repair was successful.

Permit conditions will be added to the permit to ensure compliance with this Subpart.

<u>40 CFR Part 63, Subpart DDDDD, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters</u>
Per Section §7485, the requirements of this Subpart apply to owners and operators of industrial, commercial, or institutional boilers or process heaters that are located at, or are part of, a major source of HAP as defined in Section §63.2, except as specified in Section §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575. Section §63.7575 states that for major source determinations for oil and natural gas production facilities, emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control.

Aera operates several boilers and heaters that may potentially be subject to the requirements of this Subpart. Below is the list of equipment operated by the facility that potentially be subject to this Subpart:

- Small heater treaters
- Large natural gas-fired steam generators

The small fuel oil or natural gas-fired boilers and heaters are used to aid separation of water and heavy crude oil through application of heat. The surface site consisting of all seven permitted heater treaters is co-located with the San Ardo Oil Treatment Facility. A list of equipment is shown in the following **[REF _Ref494114391 \h * MERGEFORMAT]**.

Table [SEQ Table * ARABIC]. Aera San Ardo Heater Treaters.

ID	Description	Burner rating (MMBtu/hr)	Annual fuel limit (MMBtu/yr)	Annual fuel limit notes
San Ardo Oil Treatment Facility			**772,632**	

ID	Description	Burner rating (MMBtu/hr)	Annual fuel limit (MMBtu/yr)	Annual fuel limit notes
CTB-1	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr
CTB-2	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr
CTB-3	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr
CTB-4	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr
CTB-5	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr
CTB-7	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr
CTB-8	Heater Treater	Burner 1: 6.3 Burner 2: 6.3	110,376	Annual operating time: 8,760 hr/yr

Aera showed that the San Ardo Oil Treatment Facility, which has a fuel capacity of 772,632 MMBtu/yr, does not have the potential to exceed 10 tons or more per year of any one HAP or 25 tons per year of any combination of HAPs. The combine HAP emissions are expected to be 0.023 tons per year. Thus, oil treatment facility is not considered a major source of HAPs and the requirements of this Subpart do not apply to these sites.

[REF _Ref494116430 \h * MERGEFORMAT] shows the HAP potential to emit from the San Ardo heater treaters. The emission factors used are from the 1992 Western States Petroleum Association testing of a number of heater treaters to determine the air toxics for use in the California AB2588 air toxics inventory program.

Table [SEQ Table * ARABIC]. Aera San Ardo Heater Treater HAP emissions.

CAS #	Compound	HAP	Emission factor (lb/MMcf)[1]	Annual emissions (ton/yr)[2]
71432	Benzene	Y	1.70E-03	0.001
108883	Toluene	Y	3.20E-02	0.012
100414	Ethyl Benzene	Y	1.10E-03	0.000
95476	Total Xylene	Y	1.90E-02	0.007
50000	Formaldehyde	Y	3.30E-03	0.001
75070	Acetaldehyde	Y	3.10E-03	0.001
107028	Acrolein	Y	2.30E-03	0.001
115071	Propylene	N	4.60E-01	
91203	Naphthalene	Y	2.37E-04	0.000
203968	Acenaphthylene	Y	1.20E-05	0.000
83329	Acenaphthene	Y	1.20E-06	0.000
86737	Fluorene	Y	4.60E-06	0.000
85018	Phenanthrene	Y	3.40E-05	0.000
120127	Anthracene	Y	1.40E-06	0.000
218019	Chrysene	Y	1.00E-06	0.000
56553	Benz(a)anthracene	Y	1.00E-06	0.000

CAS #	Compound	HAP	Emission factor (lb/MMcf)[1]	Annual emissions (ton/yr)[2]
205992	Benzo(b)fluoranthene	Y	5.60E-07	0.000
205823	Benzo(j)fluoranthene	Y	1.20E-05	0.000
207089	Benzo(k)fluoranthene	Y	5.60E-07	0.000
50328	Benzo(a)pyrene	Y	5.60E-07	0.000
193395	Indeno(1,2,3-c,d)pyrene	Y	5.60E-07	0.000
53703	Dibenzo(a,h)anthracene	Y	5.60E-07	0.000
191242	Benzo(g,h,i)perylene	Y	8.70E-07	0.000
	PAH	Y	7.60E-05	0.000
			Total HAPs emissions (ton/yr):	0.023

[1] Emission factors obtained from the 1992 WSPA Pooled Source Testing for AB2588, Table 1, Texaco Heater Treater.
[2] Emissions based on annual fuel limit of 772,632 MMBtu/hr and the AP-42 natural gas heating value of 1,020 Btu/Scf. Sample calculation for formaldehyde: (3.30E-02 lb/MMcf) (772,632 MMBtu/yr) (MMcf/1,020 MMBtu) (ton/2,000 lb) = 0.001 ton/yr

The large natural gas-fired boilers are used to provide steam to the petroleum reservoir to enhance the production of heavy crude oil. The steam generators are grouped in two distinct surface sides dedicated to steam generation activities. Aera provided the list of steam generators located at each of the two steam generation sites and is shown in **[REF _Ref491171592 \h * MERGEFORMAT]**.

Table [SEQ Table * ARABIC]. Aera San Ardo Steam Generator Sites.

ID	**Description**	**Burner rating (MMBtu/hr)**	**Annual fuel limit (MMBtu/yr)**	**Annual fuel limit notes**
San Ardo Generator Site 12			**5,956,800**	
12-2	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-3	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-4	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-5	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-7	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-8	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-9	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
12-10	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
San Ardo Generator Site 30			**2,934,600**	
30-1	Steam Generator	85	744,600	Annual operating time: 8,760 hr/yr
30-6	Steam Generator	62.5	547,500	Annual operating time: 8,760 hr/yr
30-9	Steam Generator	62.5	547,500	Annual operating time: 8,760 hr/yr
30-10A	Steam Generator	62.5	547,500	Annual operating time: 8,760 hr/yr
30-13	Steam Generator	62.5	547,500	Annual operating time: 8,760 hr/yr

Aera showed that the San Ardo Generator Site 12, which has the largest permitted steam generation capacity at 5,956,800 MMBtu/yr, does not have the potential to exceed 10 tons or more per year of any one HAP or 25 tons per year of any combination of HAPs. The combine HAP emissions are expected to be 0.202 tons per year. Since the San Ardo Generator Site 12 does not exceed the HAP major source thresholds, San Ardo Generator Site 30 is expected to have HAP emissions lower than the major source thresholds. Thus, neither steam generator site is considered a major source of HAPs and the requirements of this Subpart do not apply to these sites.

[REF _Ref491175210 \h * MERGEFORMAT] shows the HAP potential to emit from the San Ardo Generator Site 12. The emission factors used are from the 1992 Western States Petroleum Association testing of a number of steam generators to determine the air toxics for use in the California AB2588 air toxics inventory program.

Table [SEQ Table * ARABIC]. HAPs emissions for San Ardo Generator Site 12.

CAS #	Compound	HAP	Emission factor (lb/MMcf)[1]	Annual emissions (ton/yr)[2]
71432	Benzene	Y	1.60E-03	0.005
10883	Toluene	Y	2.00E-02	0.058
100414	Ethyl Benzene	Y	1.20E-02	0.035
95476	Total xylene	Y	2.50-02	0.073
50000	Formaldehyde	Y	4.10E-03	0.012
75070	Acetaldehyde	Y	3.00E-03	0.009
107028	Acrolein	Y	3.00E-03	0.009
115071	Propylene	N	6.00E-01	N/A
91203	Naphthalene	Y	1.87E-04	0.001
203968	Acenaphthylene	Y	3.70E-07	0.000
83329	Acenaphthene	Y	5.40E-07	0.000
86737	Fluorene	Y	2.40E-06	0.000
85018	Phenanthrene	Y	1.20E-05	0.000
120127	Anthracene	Y	2.40E-06	0.000
206440	Fluoranthene	Y	1.40E-06	0.000
12900	Pyrene	Y	2.00E-06	0.000
218019	Chrysene	Y	1.13E-06	0.000
56553	Benz(a)anthracene	Y	1.30E-06	0.000
205992	Benzo(b)fluoranthene	Y	3.70E-07	0.000
207089	Benzo(k)fluoranthene	Y	3.70E-07	0.000
50328	Benzo(a)pyrene	Y	3.70E-07	0.000
193395	Indeno(1,2,3-c,d)pyrene	Y	3.70E-07	0.000
53703	Dibenzo(a,h)anthracene	Y	3.70E-07	0.000
191242	Benzo(g,h,i)perylene	Y	3.70E-07	0.000
	PAH	Y	2.70E-05	0.000
Total HAPs emissions (ton/yr):				0.202

[1] Emission factors obtained from the 1992 WSPA Pooled Source Testing for AB2588. Table 2, Mobil Steam Generators.

[2] Emissions based on annual fuel limit of 5,956,800 MMBtu/hr and the AP-42 natural gas heating value of 1,020 Btu/Scf. Sample calculation for formaldehyde: (4.1E-03 lb/MMcf) (5,956,800 MMBtu/yr) (MMcf/1,020 MMBtu) (ton/2,000 lb) = 0.012 ton/yr.

No conditions pertaining to this Subpart are included on the permit.

<u>40 CFR Part 63, Subpart JJJJJJ, NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources</u>

The requirements of this subpart apply to owners or operators of industrial, commercial, or institutional boilers as defined in §63.11237 that are located at, or is part of, an area source of HAPs, as defined in §63.2, except as specified in §63.11195. As demonstrated above, the steam generator sites are not major sources of HAPs and are potentially subject to the requirements of this subpart.

Per Section §63.11195(e), gas-fired boilers are not subject to this Subpart. No conditions pertaining to this Subpart are included on the permit.

40 CFR Part 64 - Compliance Assurance Monitoring

Per Section §64.2(a), an emission unit is subject to 40 CFR 64, Compliance Assurance Monitoring, if the unit is subject to a federally enforceable requirement for a pollutant, the pollutant is controlled by an abatement device, and the emissions of the pollutant before abatement are more than 100% of the major source thresholds.

Cogeneration Facilities – For the purposes of 40 CFR Part 64, each gas turbine/HRSG set is considered an emission unit. The District examined the gas turbine pre-control potential to emit for NO_x, CO, SO_x, PM and VOC to determine the applicability the Compliance Assurance Monitoring (CAM) requirements. The pre-control emissions from the gas turbine/HRSG set were estimated using the emission factors from US EPA AP-42. [REF _Ref485970018 \h * MERGEFORMAT] shows the gas turbine pre-control yearly emissions based on AP-42 emission factors for natural gas-fired turbines with water-steam injection (Table 3.1-1 and Table 3.1-2a dated 4/00).

Table [SEQ Table * ARABIC]. Gas turbine pre-control yearly emissions.

Pollutant:	Gas turbine rating (MMBtu/hr)	Emission factors[1] (lb/MMBtu)	Hours of operation per year (hr/yr)	Maximum emissions (ton/yr)
NO_x	61.5	0.13	8,760	35.02
CO	61.5	0.030	8,760	8.08
SO_x	61.5	3.40E-03	8,760	0.92
PM	61.5	6.60E-03	8,760	1.78
VOC	61.5	2.10E-03	8,760	0.57

[1]Emissions factors from AP-42 Chapter 3.1, Table 3.1-1 and Table 3.1-2a (April 2000). Used emission factors for turbines with water-steam injection for NO_x and CO.

[REF _Ref485970205 \h * MERGEFORMAT] shows the yearly emissions from the heat recovery steam generator (HRSG) based on AP-42 emission factors for natural gas fired small boilers rated <100 MMBtu/hr (Table 1.4-1 dated 7/98).

Table [SEQ Table * ARABIC]. HRSG with duct burner pre-control yearly emissions.

Pollutant:	Duct burner rating (MMBtu/hr)	Emission factors[1] (lb/MMBtu)	Hours of operation per year (hr/yr)	Maximum emissions (ton/yr)
NO_x	38.7	9.80E-02	8,760	16.61
CO	38.7	8.24E-02	8,760	13.97
SO_x	38.7	5.88E-04	8,760	0.10
PM	38.7	7.45E-03	8,760	1.26
VOC	38.7	5.39E-03	8,760	0.91

[1]Emissions factors from AP-42 Chapter 1.4 (July 1998).

[REF _Ref485970500 \h * MERGEFORMAT] shows the pre-control yearly emissions from the gas turbine/HRSG set. As shown in [REF _Ref485970500 \h * MERGEFORMAT] the pre-control emissions are below the major source thresholds. Thus, CAM requirements do not apply to the gas turbine/HRSG set.

Table [SEQ Table * ARABIC]. Gas turbine/HRSG set yearly pre-control emissions.

Pollutant:	Maximum emissions (ton/yr)
NO_x	51.63
CO	22.05
SO_x	1.02
PM	3.04
VOC	1.48

Steam Generator 30-6 and 30-10A – These steam generators are equipped with a common post-incineration flue gas sulfur scrubber for the control of SO_x emissions. The units are permitted to fire a mixture of natural gas and vapor recovery gas produced in association with Aera's oil production. Pre-control potential to emit for each generator is based on burning the maximum possible volume of vapor recovery gas within actual operational constraints. This approach is used because the sulfur content of the vapor recovery gas is the determining factor in the pre-control sulfur content of the steam generator exhaust. The maximum possible volume of vapor recovery gas will result in the maximum SO_x emissions.

The amount of vapor recovery gas that can be burned in a steam generator is limited by a combination of three main factors. These factors are the amount of vapor recovery gas available, the amount of vapor recovery gas that a steam generator can burn before the combustion becomes unstable, and any permit limit on the amount of gas that can be burned in the generator. Using this volume and the typical sulfur content of the vapor recovery gas, the pre-control potential to emit is calculated as follows:

$$PreControl: SO_2\left(\frac{ton}{yr}\right) = \left(\frac{S\ ppm}{1{,}000{,}0000}\right) x \left(\frac{VaporRecoveryGas, scf}{year}\right) x \left(\frac{lbmol\ S}{379\ scf\ S}\right) x \left(\frac{64\ lb\ SO_2}{lbmole\ S}\right) x \left(\frac{ton}{2{,}000\ lb}\right)$$

Where:

$$S = typical\ sulfur\ content\ as\ H_2S = 9{,}000\ ppm\ (provided\ by\ facility)$$

$$Vapor\ Recovery\ Gas = Maximum\ vapor\ recovery\ gas = 289\frac{MMCF}{year}(provided\ by\ the\ facility)$$

$$PreControl: SO_2\left(\frac{ton}{yr}\right) = 242\ tons\ SO_2/year$$

Based on the information provided by the facility, the expected pre-control emissions are 242 tons per year. Thus, steam generators 30-6 and 30-10A are subject to the requirements of 40 CFR Part 64. Compliance with the SO_x emission limits is indirectly monitored by measuring the water recycle rate and the pH of the scrubber water. Previous source tests and operations data show that a minimum pH of 6.6 and a minimum water recycle rate of 700 gpm verify compliance with the permitted SO_x limits. At least one data point each for the pH and the water recycle rate will be collected once a day. Methodology for monitoring will be a pH meter and a flow measuring device.

Steam Generator 30-9 – The steam generator is permitted to fire a mixture of natural gas and vapor recovery gas produced in association with Aera's oil production. The unit is also equipped with a post-incineration scrubber and has the same potential to emit SO_x emissions as steam generators 30-6 and 30-10. Thus, the unit is subject to the requirements of 40 CFR Part 64. Compliance with the SO_x emission limits is indirectly monitored by measuring the water recycle rate and the pH of the scrubber water. The permit requires that a minimum pH of 4.6 and a minimum water recycle rate of 200 gpm to verify compliance with the permitted SO_x limits. Since this equipment is not presently operating, these parameters will need to be re-defined and submitted to the District within 60 days of start-up of this equipment.

Appropriate conditions are included on the permit to ensure compliance with the provisions of this Subpart.

PERMIT SHIELD[tc \l1 "PERMIT SHIELD]

District Rule 218 allows for creation of a permit shield provision. A permit shield is a provision stating that compliance with the conditions of the Federal Operating Permit (FOP) shall be deemed compliance with any applicable requirements as of the date of FOP issuance.

The District is proposing changes to the permit shield to reflect the proposed change to remove the CEMS from the gas turbines. Also, the District is proposing to make minor changes to the calculations included in the permit shield to make it easier to follow. The section pertaining to the requirements of 40 CFR Part 60, Subpart GG of the permit shield will be modified as follows:

"40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines
The cogeneration facilities at this facility are subject to the requirements of this NSPS. In addition to the post combustion control of SCR, the turbine utilizes water injection to control NO_x formation.

The NO_x emission factor from Section 60.332(a)(2) would be 150 ppmvd. This 150 ppmvd limit far exceeds the ~~NZR~~ NSR permit limit of 3.8 lbs NO_x/hr which equates to 17.6 ppmv ~~[(3.8 lbs NO_x/MMBtu)((MM lbmoles air)/(46.0 lbmole NO_2))*((379 Ft^3 Air)/(lbmole air))/((29,700 SDCFM)*(60 M/Hr)) = 17.6 ppmv]~~* [(3.8 lbs NO/Hr) (1E06) (379 ft^3/lbmole) (lbmole/46 lb NO) (hr/60 min) (min/29,700 ft^3) = 17.6 ppmv] *established by District Rule 207. Therefore, the NO_x limit from the NSPS will be subsumed under the NSR permit requirements that will be included on the Title V permit.*

The SO_2 limit from Section 60.333 would be 150 ppmv. Compliance with this limit is assumed due to these units being fired exclusively on natural gas and based upon the SO_2 limit contained in the NSR permits of 0.1 lb/hr per unit. The SO_2 concentration at this permitted emission level would be 0.33 ppmv ~~[(0.1 lbs SO_2/hr)((MM lbmoles air)/(64.1 lbmole SO_2))*((379 Ft^3 Air)/(lbmole air))/((29,700 SDCFM)*(60 M/Hr)) = 0.33 ppmv]~~* [(0.1 lbs SO_2/Hr) (1E06) (379 ft^3/lbmole) (lbmole/64.1 lb SO_2) (hr/60 min) (min/29,700 ft^3) = 0.33 ppmv]. *This value is well below the 150 ppmv SO_2 allowed for in the NSPS. Therefore, the SO_2 emission standard from this NSPS will be subsumed under the NSR permit requirement that will be included on the Title V permit.*

The testing and monitoring requirements contained in Sections 60.334 and 60.335 will be subsumed under the testing and monitoring requirements established under the NSR permits that will be included on the Title V permit. This will include the annual emissions testing. ~~requirement and the requirement to monitor operations with the use of CEMs.~~"

THE FOLLOWING WILL BE INCLUDED ON THE TITLE V PERMIT:[TC \l1 "THE FOLLOWING WILL BE INCLUDED ON THE TITLE V PERMIT:]

The permit conditions listed on the Title V Permit are derived from District issued Authorities to Construct or Permits to Operate. The permit also includes the regulatory basis for each permit condition. Permit conditions are divided into the following sections: permit shield, federally enforceable limits and standards, testing requirements and procedures, record keeping requirements, reporting requirements, and general conditions.

Permit conditions will be updated to reflect the proposed removal of the CEMS for the gas turbines and changes to the facility's equipment. Monitoring, record keeping, and reporting permit conditions will be added to comply with the fugitive emissions requirements of 40 CFR 60, Subpart OOOOa, Section §60.5397a. In addition, the District proposes update the Rule references that cite Rule 404 NO_x limits and will delete references NO_x limit of 350 ppm. The SIP adopted Rule 404 does not contain NO_x limit of 350 ppm.

FEDERALLY ENFORCEABLE EMISSION LIMITS AND STANDARDS[tc \l1 "FEDERALLY ENFORCEABLE EMISSION LIMITS AND STANDARDS]

Several conditions will be updated to account for equipment updates at the facility and the inclusion of the new parameter plan for the cogeneration units.

The District proposes to modify Condition 1:
The facility proposes to remove references to the NO_x limit of 350 ppm from District Rule 404, since the SIP approved Rule does contain a NO_x limit of 350 ppm.

1. *The pollutant mass emission rates in the exhaust discharged to the atmosphere from the heat recovery steam generator of Cogeneration Units A and B shall not exceed the following limits [District Rule 207; District Rule 403 limit of 38.2 lbs PM_{10}/hr; District Rule 404 NO_x limit of 140 lbs/hr ~~and 350 ppm~~, and SO_2 limit of 2000 ppmv; 40 CFR Part 60, Subpart GG NO_x limit of 150 ppm and SO_2 limit of 150 ppm]:*

Pollutant	*Lbs/Hour*	*Lbs/Day*
Oxides of Nitrogen (NO_x)	*3.8*	*90.7*
Carbon Monoxide (CO)	*7.0*	*168.8*
Ammonia (NH_3)	*0.4*	*33.5*
Particulate Matter <10 microns (PM_{10})	*0.81*	*19.3*
Volatile Organic Compounds (VOC)	*1.0*	*24.1*
Sulfur Dioxide (SO_2)	*0.1*	*1.0*

These limits shall not apply during startup, which is not to exceed two hours in length, or shut down, which is not to exceed one hour in length. SCR catalytic controls, water injection and good operating practices shall be used to the fullest extent during startup to minimize pollutant *emissions.*

The District proposes new Condition:
The District proposes to add a new condition to add the new parameter plan for the cogeneration units as follows:

The NO_x emission from the cogeneration units shall be controlled at all times by water injection and operation of the selective catalytic reduction (SCR) system except during startup and shutdown. To ensure proper operation the water injection and SCR control systems, the facility must maintain operate the systems with the following parameters: [40 CFR 60, Subpart GG]

Parameter	*Minimum Value:*	*Maximum Value:*	*Reporting*
Water/Fuel Ratio	*0.5 lb H_2O/lb Fuel*	*0.9 lb H2O/lb fuel*	*Average hourly*
Catalyst Temperature	*450°F*	*900°F*	*Average hourly*
NH_3 Injection Rate	*900 Liter/Hour*	*1,800 liters/hr*	*Average hourly*

These limits shall not apply during startup, which is not to exceed two hours in length, or shut down, which is not to exceed one hour in length. SCR catalytic controls, water injection and good operating practices shall be used to the fullest extent during startup to minimize pollutant emissions.

The District proposes to delete Conditions 2 & 3:
Cogeneration Unit C was not installed and the facility has cancelled the ATC, ATC no. 12904.

~~2. Oxides of nitrogen, as NO_2, in the exhaust discharged to the atmosphere from the heat recovery steam generator of Cogeneration Unit C shall not exceed 9 ppmvd, calculated as a clock hour average at 15 percent O_2, dry. [District Rule 207; 40 CFR Part 60, Subpart GG NO_x limit of 150 ppm]~~

~~3. The pollutant mass emission rates in the exhaust discharged to the atmosphere from the heat recovery steam generator of Cogeneration Unit C shall not exceed the following limits [District Rule 207; District Rule 403 limit of 38.2 lbs PM_{10}/hr; District Rule 404 NO_x limit of 140 lbs/hr and 350 ppm, and SO_2 limit of 2000 ppmv; 40 CFR Part 60, Subpart GG NO_x limit of 150 ppm and SO_2 limit of 150 ppm]:~~

~~Pollutant~~	~~Lbs/Hour~~	~~Lbs/Day~~
~~Oxides of Nitrogen (NO_x)~~	~~3.3~~	~~79.8~~
~~Carbon Monoxide (CO)~~	~~7.0~~	~~168.8~~
~~Ammonia (NH_3)~~	~~1.4~~	~~33.5~~
~~Particulate Matter <10 microns (PM_{10})~~	~~0.81~~	~~19.3~~
~~Volatile Organic Compounds (VOC)~~	~~1.0~~	~~24.1~~
~~Sulfur Dioxide (SO_2)~~	~~0.1~~	~~1.0~~

~~These limits shall not apply during startup, which is not to exceed two hours in length, or shut down, which is not to exceed one hour in length. SCR catalytic controls, water injection and good~~

~~operating practices shall be used to the fullest extent during startup to minimize pollutant emissions.~~

The District proposes to modify Conditions 6, 7, and 8:
The proposal is to update the numbering of the Steam Generators rated at 85 MMBtu/Hr. Units 22-1 through 22-4 and 30-5 have been renumber to 12-2, 12-3, 12-4, 12-5, 12-7, 12-8, 12-9, 12-10.

6. *The pollutant mass emission rates in the exhaust discharged to the atmosphere from Steam Generators ~~22-1 through 22-4 and 30-1 through 30-5~~ 12-2, 12-3, 12-4, 12-5, 12-7, 12-8, 12-9, 12-10 and 30-1 shall not exceed the following limits [District Rule 207; District Rule 403 limit of 0.82 lbs PM_{10}/hr; District Rule 404 NO_x limit of 140 lbs/hr and SO_2 limit of 2000 ppmv]:*

Pollutant	*Lbs/Hour*	*Lbs/Day*
Oxides of Nitrogen (NO_x)	*0.93*	*22.3*
Carbon Monoxide (CO)	*2.51*	*60.4*
Particulate Matter <10 microns (PM_{10})	*0.65*	*15.5*
Volatile Organic Compounds (VOC)	*0.08*	*1.9*
Sulfur Dioxide (SO_2)	*0.18*	*4.4*

7. *The emissions of oxides of nitrogen, as NO_2, in the exhaust discharged to the atmosphere from Steam Generators ~~22-1 through 22-4 and 30-1 through 30-5~~ 12-2, 12-3, 12-4, 12-5, 12-7, 12-8, 12-9, 12-10 and 30-1 shall not exceed 9 ppmvd, calculated at 3 percent O_2, dry. [District Rule 207]*

8. *The emissions of carbon monoxide in the exhaust discharged to the atmosphere from Steam Generators ~~22-1 through 22-4 and 30-1 through 30-5~~ 12-2, 12-3, 12-4, 12-5, 12-7, 12-8, 12-9, 12-10 and 30-1 shall not exceed 40 ppmvd, calculated at 3 percent O_2, dry. [District Rule 207]*

The District proposes to delete Condition 11.
The desulfurization plant was not installed and the ATC, ATC no. 13721, has been canceled.

~~11. Total produced gas which bypasses the desulfurization plant combusted in steam generator 30-9 shall not exceed 1.0 MMCFD. [District Rule 207]~~

The District proposed to updated Condition 12:
The proposal is to remove the references to the desulfurization plant. The desulfurization plant was not installed and ATC 13721 has been canceled.

12. *Total produced gas ~~which bypasses the desulfurization plant~~ combusted in steam generators 30-6 and 30-10A shall not exceed 1.5 MMCFD for each unit, and shall not exceed 2.8 MMCFD for both units combined. [District Rule 207]*

The District proposes to update Condition 16:
The proposal is to update the numbering of the Steam Generators rated at 85 MMBTU/hr. The condition will be updated to remove the use of produced gas from the desulfurization unit. The desulfurization plant was not installed and the ATC 13721 has been canceled.

16. *The cogeneration facilities and Steam Generators ~~22-1 through 22-4, 30-1 through 30-5~~ 12-2, 12-3, 12-4, 12-5, 12-7, 12-8, 12-9, 12-10, 30-1 and 30-13 shall only be fired on natural gas ~~or treated produced gas discharged from the SulFerox Desulfurization Unit~~. [District Rule 207]*

The District proposes to delete Conditions 17 and 18:
The desulfurization plant was not installed and ATC 13721 has been canceled.

~~*17. The H_2S concentration in the treated produced gas discharged from the SulFerox Desulfurization Unit shall not exceed 0.00152 pounds of H_2S per 1,000 cubic feet of gas (1 grain/100 SCF). [District Rule 207]*~~

~~*18. No produced gas shall bypass the SulFerox Desulfurization Unit unless it is routed to steam generators with scrubbers in full operation or to the SulfaTreat system prior to incineration. [District Rule 207]*~~

The District proposes to modify Condition 28:
The District is proposing to modify condition 28 to change the reference to the District from MBUAPCD to District.

28. *Operation of the cogeneration facilities and all steam generators must be conducted in compliance with all data and specifications submitted in the permit applications to the ~~MBUAPCD~~District. [District Rule 207]*

The District proposes to delete Condition 25:
The utility flare was not installed. The utility flare was part of the project to upgrade the Central Treatment Complex under ATC 14583. ATC 14583 has been canceled.

~~*25. The Utility Flare shall only be operated during emergency upset conditions. [District Rule 207]*~~

The District proposes to delete Condition 30:
The desulfurization plant was not installed and ATC 13721 has been canceled.

~~*30. The steam generators shall not be fired on produced gas which bypasses the Desulfurization Plant gas unless their specific air pollution control equipment is in full use. [District Rule 207]*~~

The District proposes to delete Condition 37:
The SIP adopted Ruled 404 does not have a NO_x limit of 350 ppmv from gaseous fuel fired equipment.

~~*37. Oxides of Nitrogen, calculated as nitrogen dioxide (NO_2), from all gaseous fuel fired equipment shall not exceed 350 ppmv, calculated at 3 percent O_2, dry. [District Rule 404]*~~

Aera is proposing to delete Condition 38:
Aera has stated that their equipment is not fired on fuel oil. The District will keep Condition 38, since the condition still applies to the drilling rigs with diesel fired internal combustion engines.

38. The sulfur content on any fuel oil used at the facility shall not exceed 0.5 percent by weight. [District Rule 412]

The District proposes to modify Condition 39:
The proposal is to remove references to the desulfurization plant. The desulfurization plant was not installed and ATC 13721 has been canceled.

39. The sulfur content on any gaseous fuel used at the facility shall not contain sulfur compounds, calculated as hydrogen sulfide at standard conditions, in excess of 50 grains per 100 cubic feet. [District Rule 412]

This condition does not apply to produced gas which ~~bypasses the desulfurization plant and~~ is combusted in the steam generators with scrubbers. [District Rule 413]

TESTING REQUIREMENTS AND PROCEDURES[tc \l1 "TESTING REQUIREMENTS AND PROCEDURES]

Several conditions will be updated account for equipment updates at the facility and the proposed removal of the CEMS for the gas turbines.

The District proposed to modify Condition 58:
The proposal is to remove references to the testing to the requirements of Cogeneration Unit C. Cogeneration Unit C was not installed and the facility has cancelled the ATC no. 12904.

58 An annual performance test of each cogeneration facility shall be conducted during October of each year. ~~AERA~~ Aera Energy LLC shall conduct performance tests in accordance with EPA Method 20 or CARB Method 100 for NO_x and O_2, EPA Method 10 or CARB Method 100 for CO, EPA Method 18 or CARB Method 100 for hydrocarbons, the collection method specified in BAAQMD Method 1B and the analysis specified in EPA Method 350.3 for ammonia to verify compliance with condition number~~s~~ 1~~, 2 and 3~~. ~~AERA~~ Aera Energy LLC shall furnish the District written results of such performance tests within sixty (60) days of the test completion. A testing protocol shall be submitted to the District no later than 30 days prior to testing, and District *notification at least 10 days prior to the actual date of testing shall be provided so that a District observer can be present. The compliance test shall include, but not be limited to, the determination of the following parameters [District Rule 207]:*

a) *Oxides of Nitrogen, as NO_2: ppmv at 15% O_2, dry and lb/hr.*

b) *Carbon Monoxide: ppmv at 15% O_2, dry and lb/hr.*

c) *Ammonia: ppmv at 15% O_2, dry and lb/hr.*

d) *Volatile Organic Compounds (VOC): ppmv and lb/hr.*

and the following process parameters:

e) *Fuel(s) being fired, rate (SDCFM) and proportion of each.*

f) *Electricity generated during the test.*

g) *Ammonia injected in lb/hr, NH_3/Inlet NO_x mole ratio, and verification of ammonia slip calculation used in weekly calculation.*

h) *Water injection rate and water to fuel ratio.*

If the testing cannot be completed during the month of October and if AERA Energy LLC can establish that the cogeneration facility was not operating for a period of time that could have allowed the testing to be completed, the testing can be delayed, such that it is conducted within thirty days from the date on which the turbine is restarted, and comply with the following notification requirements:

A) *~~AERA~~ Aera Energy LLC must notify the District that they will be unable to meet the October testing requirement as soon as it becomes known, but in no event later than October 30.*

B) *~~AERA~~ Aera Energy LLC must provide the District with at least five days prior notification of the anticipated date the cogeneration facility will be restarted.*

C) *~~AERA~~ Aera Energy LLC must provide the District with the time and date of cogeneration facility startup within 24 hours after the actual startup.*

The District proposes to modify Condition 59:
The proposal is to remove references to the desulfurization plant. The desulfurization plant was not installed and ATC 13721 has been canceled. Also, the deadline for the annual source test will be changed from January 1 to December 31 of each year.

59. *An annual performance test of each steam generator operated on natural gas ~~and/or produced gas~~*

~~treated by the desulfurization plant~~ during the year shall be conducted prior to ~~January 1~~ December 31 of each year. ~~AERA~~ Aera Energy LLC shall conduct performance tests in accordance with EPA Method 7E or CARB Method 100 for NO_x, EPA Method 10 or CARB Method 100 for CO, EPA Method 3A or CARB Method 100 for O_2 to verify compliance with condition numbers ~~4~~ 3 through ~~8~~7. ~~AERA~~ Aera Energy LLC shall furnish the District written results of such performance tests within sixty (60) days of the test completion. A testing protocol shall be submitted to the District no later than 30 days prior to testing, and District notification at least 10 days prior to the actual date of testing shall be provided so that a District observer can be present. The compliance test shall include, but not be limited to, the determination of the following parameters [District Rule 207]:

a) Carbon Monoxide: ppmv at 3% O_2, dry and lb/hr.

b) Oxides of Nitrogen, as NO_2: ppmv at 3% O_2, dry and lb/hr.

and the following process parameter:

c) Fuel(s) being fired, rate (SDCFM) and proportion of each.

The District proposes to delete Condition 61.
The desulfurization plant was not installed and ATC 13721 has been canceled.

~~61. AERA Energy LLC shall conduct testing of the H_2S concentration downstream of the SulFerox Desulfurization Unit and Sulfatreat Vessels not less than once every 24 hours with the use of gas detector tube sampling as approved by the District to verify compliance with condition numbers 17 and 23. [District Rules 207& 218]~~

Aera is proposing to delete Condition 63:
Aera has stated that their equipment is not fired on fuel oil. The District will keep Condition 63, since the condition still applies to the drilling rigs with diesel fired internal combustion engines.

63. No testing is specified for the generic (Rule 400) opacity requirement from condition number ~~33~~ 27 while firing on natural or produced gas. When firing on fuel oil continuously for a period of 120 hours and at intervals of seven (7) days during continuing operation on fuel oil, ~~AERA~~ Aera Energy LLC shall conduct testing in accordance with the methodology contained in EPA Method 9 and the averaging/aggregating period contained in District Rule 400 to verify compliance with condition number ~~33~~27. [District Rule 218]

Aera is proposing to delete Condition 67:
Aera has stated that their equipment is not fired on fuel oil. The District will keep Condition 67, since the condition still applies to the drilling rigs with diesel fired internal combustion engines.

67. Testing of all fuel oil delivered to the facility shall be conducted prior to or upon receipt of the fuel oil, or in lieu of testing a manufacturers certification of the sulfur content of the fuel oil shall be

supplied at the time of delivery. ~~AERA~~ Aera Energy LLC shall conduct testing in accordance with ASTM D1552-83, ASTM D1266-87 or ASTM D2622-87 or shall receive certification as to the sulfur content of the fuel oil from the manufacturer to verify compliance with condition number ~~38~~31. AERA Energy LLC shall furnish the District the certification or written results of the test prior to firing the fuel oil, but in no case later than thirty (30) days of completion. [District Rule 218]

The District proposes to modify Condition 68:
The proposal is to remove references to the desulfurization plant. The desulfurization plant was not installed and ATC 13721 has been canceled. Also, the deadline for the annual source test will be changed from January 1 to December 31 of each year.

68. An annual performance test of each steam generator firing produced gas ~~which bypasses the desulfurization plant~~ shall be conducted on or prior to ~~January 1~~ December 31 of each year. ~~AERA~~ Aera Energy LLC shall conduct performance tests in accordance with EPA Methods 2, 2A, 2C, or 2D for measuring flow rates and EPA Methods 18, 25, 25A, or 25B for measuring the total gaseous organic concentrations at the inlet and outlet of the control device to verify compliance with condition number ~~44~~37. ~~AERA~~ Aera Energy LLC shall furnish the District written results of such performance tests within sixty (60) days of the test completion. A testing protocol shall be submitted to the District no later than 30 days prior to testing, and District notification at least 10 days prior to the actual date of testing shall be provided so that a District observer can be present. [District Rule 218, District Rule 427]

MONITORING AND RECORD KEEPING REQUIREMENTS[tc \l1 "MONITORING AND RECORD KEEPING REQUIREMENTS]

Several conditions will be updated account for equipment updates at the facility, the proposed removal of the CEMS for the gas turbines, and the fugitive emissions requirements of Section §60.5397a.

The District proposes to Delete Condition 70.
Aera is proposing to remove the CEMS system from the cogeneration facilities. Also, the requirements of Rule 213 and 40 CFR 64 do not apply to the gas turbines as stated above in the Rule Compliance Determination Section.

~~70. Continuous emission monitoring systems must be calibrated and operated to measure the cogeneration facilities exhaust stack for~~ ~~NO_x, CO and O_2. The system shall continuously record the NO_x and CO concentrations corrected to a value of 15 percent O_2, dry, and the NO_x and CO mass emission rates in pounds per hour and pounds per day. The system shall meet all the requirements of Rule 213 and shall be certified at least once per year. [District Rule 207; District Rule 213; 40 CFR Part 64]~~

~~Any breakdown of the CEM system shall be reported to the District within 1 hour of the occurrence,~~

~~and the CEM defect shall be repaired within 96 hours or the monitored equipment shall be shut down until such repair is completed.~~

The District proposes to modify Condition 73:
The proposal is to require the facility to record the inlet temperature and pressure differential across the SCR catalyst on an hourly basis. The modification is to ensure that the facility is on compliance with the proposed parameter monitoring plan as required per 40 CFR 60, Subpart GG, Section §60.334(g).

73. Instrumentation must be operated to measure the SCR catalyst inlet temperature and pressure differential across the SCR catalyst and to record the SCR catalyst inlet temperature on an average hourly basis. [District Rule 207 and 40 CFR Part 60, Subpart GG]

The District proposes to add a new Condition:
The District is proposing to require the facility to continuously monitor and record the NH_3 injection rate on average hourly basis as proposed by the new parameter monitoring plan for the cogeneration units.

A continuous monitoring system must be operated to monitor and record the NH_3 injection rate on an average hourly basis. [40 CFR 60, Subpart GG]

The District proposes to delete Condition 76:
The desulfurization plant was not installed and ATC 13721 has been canceled.

~~*76. AERA Energy LLC shall maintain daily records of the quantity of produced gas which bypasses the Desulfurization plant and is combusted in each Steam Generator and the flare. [District Rule 207]*~~

The District proposes new Condition:
The District proposed to add a new monitoring condition that covers the fugitive emissions monitoring requirements of 40 CFR 60 Section §60.5397a.

Aera must monitor and repair all fugitive emissions components at well sites, as defined in Section §60.5430a, which are subject to the fugitive emissions requirements of Section §60.5397a. Fugitive emissions are defined as: any visible emission from a fugitive emissions component observed using optical gas imaging (OGI) or an instrument reading 500 ppm or greater using Method 21. Aera must meet the following requirements [40 CFR 60, Subpart OOOOa]:

a) Aera must develop a fugitives monitoring plan that incorporates the required elements of Section §60.5397a(a) and (c).

b) Aera must conduct an initial monitoring survey within 60 days of the startup of production for each collection of fugitive emissions components at a new well site or by June 3, 2017 whichever is later. For modified or reconstructed well sites, the initial monitoring survey must be conducted within 60 days of first day of production or by June 3, 2017 whichever is later.

c) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least four (4) months apart.

i) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than two (2) meters above the surface may be designated as difficult-to-monitor. Difficult-to-monitor fugitive emissions components must be monitored at least once per calendar year. The written fugitive emissions monitoring plan required by this condition must: identify these components, identify the location of each of these components and must include an explanation of why each designated component is difficult to monitor.

ii) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. The written fugitive emissions monitoring plan required by this condition must: identify these components, identify the location of each of these components, must include an explanation of why each designated component is unsafe to monitor and must include a schedule for monitoring the fugitive emissions at these sites.

d) Each monitoring survey shall observe each fugitive emissions component, as defined in Section §60.5430a, for fugitive emissions.

e) Aera must repair or replace each identified source of fugitive emissions as soon as practicable, but no later than 30 calendar days after detection of fugitive emissions. If the repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within two (2) years, whichever is earlier. Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 calendar days after being repaired, to ensure that there are no fugitive emissions.

i) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired the components using either Method 21 or optical gas imaging within 30 calendar days of finding such fugitive emissions. Additionally, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

ii) Operators that use Method 21 to resurvey the repaired fugitive emissions components must follow the written fugitive emissions monitoring plan required by this condition. A fugitive emissions component is repaired when the use of Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 are used.

iii) Operators that use the optical gas imaging to resurvey the repaired fugitive emissions components must follow the written fugitive emissions monitoring plan required by this condition. A fugitive emissions component is repaired when the use of the optical gas imaging instrument shows no indication of visible emissions.

The District proposes new Condition:
The District proposed to add a new recordkeeping condition that covers the fugitive emissions monitoring requirements of 40 CFR 60 Section §60.5397a.

Aera shall maintain the following records for each collection of fugitive emissions components at a well [40 CFR 60, Subpart OOOOa]:

a) The fugitive emissions monitoring plan, as required in Condition 68.

b) The records of each monitoring survey including the following:

A. Date of survey.
B. Beginning and end time of the survey.
C. Name of operator(s) performing survey. You must note the training and experience of the operator.
D. Monitoring instrument used.
E. When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.
F. Fugitive emissions component identification when Method 21 is used to perform the monitoring survey.
G. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.
H. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
I. Documentation of each fugitive emission, including the information listed below:
i. Location.
ii. Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
iii. Number and type of components for which fugitive emissions were detected.

iv. *Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.*

v. *Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.*

vi. *Number and type of fugitive emissions components that were not repaired as required in Condition 68(e).*

vii. *Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in Condition 68(e).*

viii. *If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in Condition 68(e). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements of this condition under (b)(E), as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.*

ix. *Repair methods applied in each attempt to repair the fugitive emissions components.*

x. *Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.*

xi. *The date of successful repair of the fugitive emissions component.*

xii. *Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.*

REPORTING REQUIREMENTS[tc \l1 "REPORTING REQUIREMENTS]

Conditions will be updated account for equipment updates at the facility, the removal of the CEMS, and the fugitive emissions requirements of Section §60.5397a.

The District proposes to delete Condition 86:
Since the CEM equipment for the cogeneration facilities will be removed, this condition can be removed. Note that the reporting requirements of existing Condition 92 applies to the cogeneration facilities and retains the requirement to reports of Condition 86.

~~86. AERA Energy LLC shall submit to the Air Pollution Control District a written report each month on the cogeneration facilities which shall include [District Rule 207]:~~

~~*a) time intervals, date, and magnitude of excess emissions;*~~

~~*b) nature and cause of the excess emission, and corrective actions taken;*~~

~~*c) time and date of each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; and*~~

~~*d) a negative declaration when no excess emissions occurred.*~~

The District proposes to delete Condition 87:
The desulfurization plant was not installed and ATC 13721 has been canceled.

~~*87. AERA Energy LLC shall submit to the Air Pollution Control District a written report each month on the produced gas treated by the SulFerox Desulfurization Unit which shall include [District Rule 207]:*~~

~~*a) average daily H_2S concentration, ppm;*~~

~~*b) average daily gas rate, MCFD; and*~~

~~*c) date, time, duration, maximum concentration, average concentration, and volume of gas for all periods during which the H_2S concentration exceeds the limit expressed in condition 17.*~~

Aera is proposing to modify current Condition 92:
Aera is proposing to delete the reporting requirements that relate to the CEMS equipment that will be removed from the cogeneration facilities.

92. AERA Energy LLC shall submit quarterly reports to the District, in a District approved format, within 45 days from the end of the quarter and these shall include [District Rules 213 & 218]:

A) the time intervals, date and magnitude of excess emissions, nature and cause of the excess (if known), corrective actions and preventative measures adopted; and

B) the averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard for the pollutant in question; and

C) ~~*time and date of each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of system repairs and adjustments; and*~~

D) all information pertaining to any monitoring as required by the permit; and

E) a negative declaration specifying when no excess emissions occurred; and

F) ~~a summary of actual monthly emissions from the CEM for all equipment which operated during the quarter.~~

The District response to proposed Condition 92:
The District agrees with the proposed changes to remove references to the CEMS equipment from this condition.

The District proposes new Condition:
The District proposed to add a new reporting condition that covers the fugitive emissions monitoring requirements of 40 CFR 60 Section §60.5397a.

For the collection of fugitive emissions components at each well site, Aera must submit to the District an annual report which includes the records of each monitoring survey conducted the preceding year, as required in Condition (reference monitoring condition #), no later than October 31. The annual report must include the information specified below. Submittal of an annual report to the US Environmental Protection Agency following 40 CFR 60.5420a satisfies the reporting requirements listed below [40 CFR 60, Subpart OOOOa]:

a) The Date of the survey.
b) Beginning and end time of the survey.
c) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.
d) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.
e) Monitoring instrument used.
f) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
g) Number and type of components for which fugitive emissions were detected.
h) Number and type of fugitive emissions components that were not repaired as required in Condition 68(e).
i) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.
j) The date of successful repair of the fugitive emissions component.
k) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.
l) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

GENERAL CONDITIONS[tc \l1 "GENERAL CONDITIONS]

The District is proposing to add a new condition to specify the time frame for submittal of the required permit renewal application.

Proposed new Condition:

> *The renewal application for this permit shall be submitted at least 6 months but no greater than 18 months prior to permit expiration. [District Rule 218]*

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